ECONOMIC FEASIBILITY OF CARBON SEQUESTRATION WITH ENHANCED GAS RECOVERY (CSEGR)

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ABSTRACT

Prior reservoir simulation and laboratory studies have suggested that injecting carbon dioxide into mature natural gas reservoirs for carbon sequestration with enhanced gas recovery (CSEGR) is technically feasible. The physical properties of supercritical carbon dioxide favor displacement of methane with limited gas mixing making enhanced gas recovery possible at least for several years. We performed an economic sensitivity analysis of a prototypical CSEGR application at a large depleting gas field in California. The largest single expense is for carbon dioxide capture, purification, compression, and transport to the field. Other incremental costs for CSEGR include: (1) new or reconditioned wells for carbon dioxide injection, methane production, and monitoring; (2) carbon dioxide distribution within the field; and, (3) separation facilities to handle eventual carbon dioxide contamination of the methane. Economic feasibility is most sensitive to wellhead methane price, carbon dioxide supply costs, and the ratio of carbon dioxide injected to incremental methane produced. Our analysis suggests that CSEGR may be economically feasible at carbon dioxide supply costs of up to \$4 to \$12/t (\$0.20 to \$0.63/Mcf). Although this analysis is based on a particular gas field, the approach is general and can be applied to other gas fields. This economic analysis, along with prior reservoir simulation and laboratory studies that suggest the technical feasibility of CSEGR, demonstrates that CSEGR can be feasible and that a field pilot study of the process should be undertaken to test the concept further.

INTRODUCTION

Carbon dioxide (CO_2) injection into oil reservoirs for enhanced oil recovery (EOR) has been a proven technical and economic success for more than 20 years. Although the advanced technology of injecting carbon dioxide (CO_2) into mature natural gas (methane, CH_4) reservoirs for carbon sequestration with enhanced gas recovery (CSEGR) appears promising, it has not yet been tried in the field nor shown to be commercially feasible. The process of CSEGR is depicted in Figure 1 where we show the separation and compression of CO_2 from industrial and petroleum refining sources, injection into a mature natural gas reservoir, repressurization and enhanced production of CH_4, and the beneficial use of the CH_4 as a fuel. From the point of view of geologic carbon sequestration, depleted natural gas reservoirs are a promising target given their proven history of gas containment and production. The ultimate worldwide storage capacity of depleted natural gas reservoirs has been estimated at 800 Gt CO_2 (8×10^{14} kg CO_2) [1]. As for enhanced gas recovery, estimates are that 30-40% of the gas in place is left behind in water-drive gas reservoirs and approximately 10-20% is left behind in depletion-drive reservoirs (Paul Knox, pers. commun.). These large volumes of currently unrecoverable gas make potential incremental CH_4 production attractive when the alternative is field abandonment.

The process of CSEGR appears to be technically feasible based on reservoir simulation and experimental studies. In particular, we have carried out numerical simulations of CO_2 injection into model natural gas reservoirs to study the processes of reservoir pressurization, gas displacement, and gas mixing [2,3]. Simulations in the latter study made use of real-gas mixture properties in the ternary system H_2O-CO_2-CH_4 and the reservoir simulator TOUGH2/EOS7C to model flow and transport of supercritical CO_2, CH_4, and water in gas and aqueous phases in three-dimensional model reservoirs. These process simulations show that (1) the high density and viscosity of supercritical CO_2 favor CSEGR by limiting gas mixing, (2) that reservoir heterogeneity tends to accelerate breakthrough of CO_2 to production wells, but (3) that repressurization of the reservoir occurs faster than CO_2 breakthrough. An optimal injection strategy is to inject dense supercritical CO_2 into the lower portions of the reservoir to drive out the remaining lighter gas while minimizing mixing and contamination. Our simulations suggested that CSEGR is feasible from a process perspective in that the injection of CO_2 into depleted gas reservoirs can enhance CH_4 recovery, while simultaneously sequestering large amounts of CO_2. Laboratory experiments of the displacement of CH_4 by supercritical CO_2 have further demonstrated the promise of CSEGR [4].

The purpose of this study was to investigate the economic feasibility of CSEGR. We selected the Rio Vista Gas Field in the Sacramento-San Joaquin Delta area of California (USA) for initial analysis. This gas field is typical of large onshore mature gas fields not associated with oil, and has the added feature of being near potential large sources of CO_2 in the San Francisco Bay area. In our analysis, we first estimated the capital costs and operating costs for CO_2 acquisition and distribution, drilling or re-completing CO_2 injection and CH_4 production wells, gas purification and compression, and field design and monitoring. These costs are offset by the production of additional CH_4, the price of which will be variable depending on future market conditions. Although focused on a mature reservoir in California, the approach is general and can be used at other gas fields with appropriate changes in model variables. We focus our analysis on the present-day circumstances in which CO_2 must be bought from a supplier and is therefore a significant cost of CSEGR.

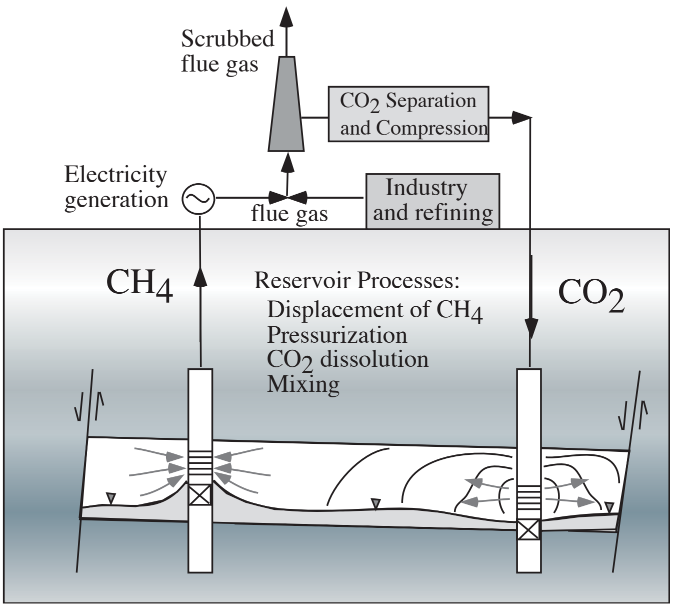

Figure 1. Schematic of CSEGR processes.

APPROACH

The economic feasibility of CSEGR depends on the incremental benefits of gas recovery relative to the incremental expenses of CSEGR. A key decision for evaluating CSEGR applications -- as well as for CO_2-enhanced oil recovery and coalbed methane projects – is proper timing: At what stage is CO_2 injection optimal? CSEGR technology may be applied at any stage in the life of a natural gas field, from initial discovery and development all the way to depletion and field abandonment. We believe that the optimal application of CSEGR is in mature (but not abandoned) natural gas fields where production is declining. We refer to such mature reservoirs that are still in production but that are becoming depleted as “depleting” reservoirs and focus our analysis on applying CSEGR at this stage in the life of the reservoir. A depleting gas field already has in place a working infrastructure of producing wells, gas gathering, treatment, compression, and transport facilities, plus the necessary regulatory approvals. In contrast, newly discovered fields lack infrastructure and their reservoir behavior is still poorly understood, making CO_2 injection more risky. Likewise, abandoned fields face large rehabilitation costs as well as regulatory hurdles. Our economic model assumes that CSEGR is applied to a depleting gas field, such as the Rio Vista field in the Sacramento Valley, the largest onshore gas field in California [5].

Incremental capital costs for CSEGR include CO_2 acquisition and transport via pipeline to the field, distribution of CO_2 within the field, injection wells, monitoring systems, CH_4 compression and (eventually) CH_4/CO_2 separation facilities. A major expense today is the cost of acquiring CO_2, which may range from $10/t from a relatively pure fertilizer or cement plant source up to $50/t for a retrofitted power plant. We assumed that CO_2 is supplied at high purity and pressure to the pipeline terminus. We computed the maximum price that the field operator could afford to pay for CO_2 supply to break even under a 15% rate of return (pre-income taxes), under varying wellhead gas price and CO_2/CH_4 ratios. We assumed that the field operator would construct a new 50-km long pipeline and pipeline distribution network to transport CO_2 from the supply source to wells throughout the field. We assumed that existing shut-in or abandoned wells could be converted to dedicated CO_2 injection or monitoring wells at a cost of approximately one-third that of drilling new wells. Eventually, injected CO_2 mixes with CH_4 within the reservoir, requiring costly gas separation and conversion of the wellhead and flow lines to corrosion-resistant materials.

We estimated capital and operating costs for the CSEGR application based on current California gas production operations and experience at natural CO_2 production fields and EOR operations. Development and cost assumptions are summarized in Tables 1 and 2. The field was designed as a simple pattern of 25 CO_2 injection wells, 16 CH_4 production wells, and 8 monitoring wells placed over the central part of the 16 km long by 7 km wide gas field, as shown schematically in Figure 2. The analysis is based on a CSEGR scenario where CO_2 is injected at a constant rate while CH_4 is produced such that reservoir pressure remains nearly constant, the so-called Scenario II simulation presented in [2]. Although Scenario II considered a two-dimensional slice of the reservoir and a single injection and production well pair, the injection and production rates scale with reservoir volume (see [3]). Injection and production is assumed to be in the Domengine sandstone, the largest gas pool at Rio Vista. Carbon dioxide injection at the field was fixed at 2.4 million t/year. For comparison, this rate is approximately 57% of the CO_2 production rate of the nearby 680 MW gas-fired powerplant at Antioch, California. Incremental CH_4 production ranged from 1.1 to 2.3 million m^3/day (40 to 80 MMcfd). Standard royalty, severance, and other production taxes were subtracted from the cash flow.

While most of the variables in the model are generalized economic variables, some depend on the physical processes of CSEGR and can be estimated from reservoir simulation results. In particular, we found a volumetric ratio of 1.7 for the CO_2 that must be injected to incremental CH_4 that is produced in the low-pressure model scenario used in this analysis [2]. Physically, this ratio represents the efficiency of EGR in terms of the displacement of CH_4 by CO_2; the closer the ratio is to unity, the more efficient is the gas recovery process. The degree to which this ratio is greater than unity can reflect the combined effects of repressurization of the reservoir, dissolution of CO_2 into connate water, gas mixing, and reservoir geometry. Briefly, the CO_2 is denser than CH_4 and the change in density of CO_2 as pressure increases through the critical pressure of 73.8 bars is much larger than the change in density of CH_4 at typical reservoir temperatures. The result of this difference is that it takes more CO_2 to displace a given volume of CH_4 in a high-pressure reservoir. However, because deeper reservoirs tend to be at higher temperatures, the effects of higher pressure on CO_2 density are moderated. Furthermore, while repressurization and dissolution tend to make the ratio larger than unity, gas mixing decreases the ratio because the density of supercritical CO_2 decreases drastically upon mixing with small amounts of CH_4 which causes pressure increases with no additional injection whatsoever (e.g., [3]). To capture the variability of the volume ratio, we tested the sensitivity of the result using values of 1.5, 2.0, and 3.0 by varying the assumed incremental CH_4 production under a constant CO_2 injection rate. Another physical property that can be estimated from simulation results is the gas composition, or mass fraction CH_4 in the produced gas. This property starts at unity in CSEGR, but declines as mixing occurs in the reservoir and CO_2 breaks through to the production wells. Prior simulation results show that the mass fraction of CH_4 declines to less than 0.5 after approximately 15 years in Scenario II [2]. For the purposes of the economic analysis presented here, we will assume that EGR is stopped (reservoir shut in) when the mass fraction of CH_4 drops below 0.5. Carbon sequestration by CO_2 injection can continue for decades after the reservoir is shut in [2].

TABLE 1

DESIGN PARAMETERS FOR CSEGR APPLICATION AT A CALIFORNIA DEPLETING GAS FIELD(US$ 2002)

Parameter	Value	
Reservoir Depth	1,500 m	4,921 feet
Reservoir Type	Sandstone, High Porosity & Permeability	
Total Field CO_2 Storage Capacity	3.6×10^7 t	0.7 Tcf
Total Field CO_2 Injection Rate	6500 t/day	125 MMcfd
CO_2 Injection Rate (per well)	260 t/day	5.0 MMcfd
CH_4 Prod. Rate (Peak incremental; per well)	48 to 95 t/day	2.5 to 5.0 MMcfd
Wellhead Natural Gas Price	\$0.11 to 0.18/m^3	\$3.00 to \$5.00/Mcf
CO_2 Injection Wells	25 wells	
CH_4 Production Wells	16 wells	
Monitoring Wells	8 wells	
Project Duration	15 years	
CO_2 Content at Production Wells	Years 1-5: 0%	
	Years 5-10: 5%	
	Years 10-15: 25%	

Mcf = 1×10^3 ft^3 = 28.3 m^3. MMcf = 1×10^6 ft^3. Tcf = 1×10^{12} ft^3. t = tonne = 1×10^3 kg.

TABLE 2

CAPITAL COSTS (US$ 2002) FOR CSEGR APPLICATION AT A CALIFORNIA DEPLETING GAS FIELD

Cost Item	Unit Cost (x 1000 US$)	Units	Total Cost (million US$)
Wells			
CH_4 Production Well: New Completion	$390	4	1.56
CH_4 Production Well: Workovers	$40	12	0.48
CO_2 Injection Well: New Completion	$460	5	2.30
CO_2 Injection Well: Converted CH_4 Well	$180	20	3.60
Monitoring Well: Converted CH_4 Well	$70	8	0.56
Total Well Costs			**8.50**
Pipelines			
CO_2 Transport Pipeline (8-Inch Diameter)	$125	50 km	6.25
CO_2 Field Distribution Lines (2-Inch Diam)	$30	10 km	0.30
Total CO_2 Pipeline & Distribution Costs			**6.55**
Total Capital Costs			**15.05**

RESULTS

The economic analysis shows that CSEGR may be economically feasible if the supply cost of CO_2 is low, if CO_2/CH_4 mixing is slow so there is little CO_2 breakthrough, and if there is a significant amount of CH_4 remaining in the reservoir to be recovered. Sensitivity analysis using the CSEGR economic model shows that the most critical parameters are wellhead natural gas price and the ratio of CO_2 injected to incremental CH_4 produced. The risk of natural gas price drop may be hedged, while capital costs may be estimated with reasonable certainty. Thus, the major remaining unknown economic factors are the volumetric CO_2/CH_4 ratio and the time to breakthrough. These key factors are likely to vary from field to field, based on reservoir architecture and field operation strategies, and can be forecasted using detailed reservoir simulation. However, field testing of CSEGR is needed to demonstrate empirically its feasibility and to clarify the influence of key economic variables.

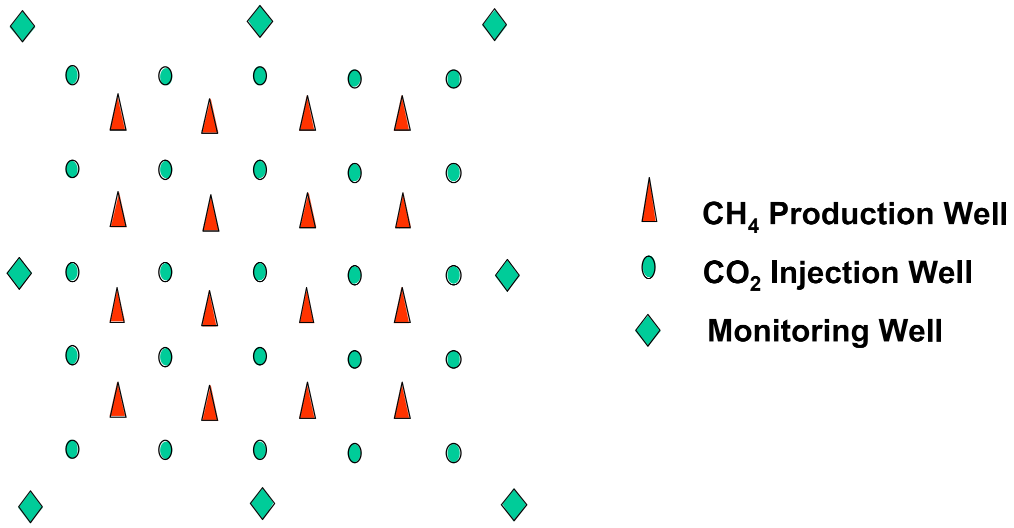

Figure 2. Schematic of well pattern for CSEGR with well spacing of one mile (1.61 km).

Figure 3 shows the results of the sensitivity analysis. The base case (CO_2/CH_4 = 1.5 and wellhead CH_4 price = \$3.00/MMBtu ≈ \$3.00/Mcf) shows that CSEGR may be economic at CO_2 supply costs of under \$8/t (\$0.40/Mcf). This breakeven threshold rises to over \$15/t (\$0.79/Mcf) at a \$5/Mcf wellhead price. These CO_2 prices are only slightly below actual current CO_2 prices from geologic sources and low-cost gas processing plants in the Permian and Rocky Mountain basins of the western USA. However, capture, separation, and compression costs from power plants are far higher, perhaps \$50/t (\$3.00/Mcf). Under current technology, CSEGR would require a significant subsidy for CO_2 sequestration to be economic using these anthropogenic CO_2 sources.

Two other sensitivity cases were run with less optimistic assumptions, using CO_2/CH_4 ratios of 2.0 and 3.0 (Figure 3). These scenarios represent fields with greater reservoir hetereogeneity and/or less remaining CH_4 in place. Breakeven CO_2 supply costs for these less favorable reservoirs ranged from \$4 to \$6/t ((\$0.21 to \$0.31/Mcf) at a \$3/Mcf CH_4 wellhead price. This is likely to be sub-economic even using low-cost natural CO_2 field sources, which do not exist in California. However, advances in CSEGR injection, production, and field management technologies could reduce CO_2/CH_4 ratios and improve CSEGR economics. Furthermore, if future CO_2 markets involve effective payment for carbon sequestration, CO_2 may be free to the operator or even become a potential revenue stream making CSEGR even more attractive economically.

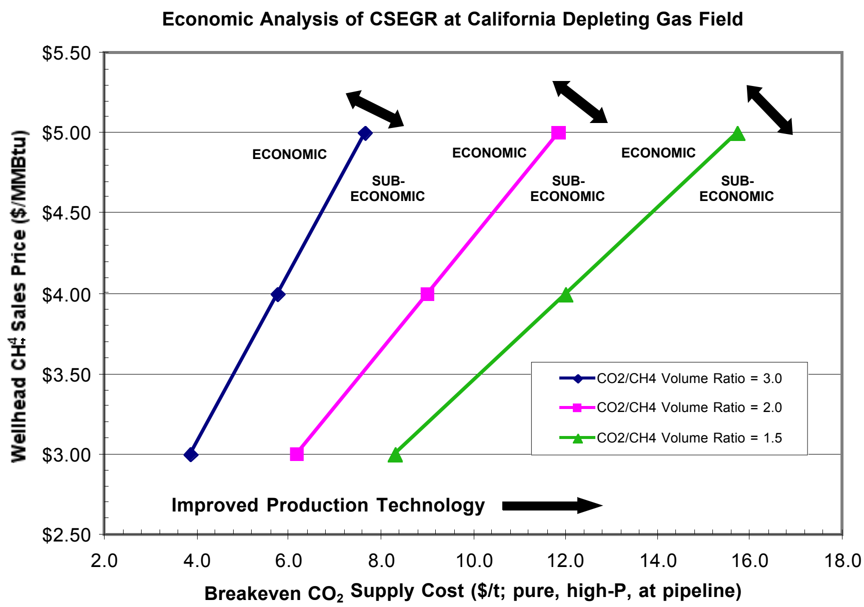

Figure 3. Results of sensitivity analysis showing actual breakeven CO_2 supply costs (no subsidy) for various CH_4 prices.

CONCLUSIONS

CSEGR may be economically feasible provided the volumetric ratio of CO_2 injected to incremental CH_4 produced is less than about three, depending on CO_2 supply costs and CH_4 wellhead prices. Many uncertainties remain in the evaluation of a new recovery and sequestration process, among which are uncertain monitoring requirements and uncertain CO_2 markets. For example, possible future CO_2 markets may involve payment to operators willing to accept CO_2 and inject it into the ground for carbon sequestration. In this case, CO_2 is no longer a cost but rather a revenue and the economics of CSEGR will be considerably more favorable. In any case, CSEGR will have to be evaluated on a field-by-field basis considering reservoir properties and conditions. The analysis in this study was based on an idealized model reservoir assuming homogeneous permeability and a single gas-bearing layer. In addition, the economic model was based on simulation results of a low-pressure reservoir, i.e., highly depleted and below the critical pressure of CO_2. For these reasons, the results of our study must be considered tentative and subject to revision as more detailed reservoir simulations are carried out. Nevertheless, our results suggest that CSEGR will be feasible under certain conditions. Because both reservoir simulation and laboratory studies have also suggested that CSEGR is technically feasible, it is now time to consider seriously the development of a field pilot-study test of CSEGR.

ACKNOWLEDGMENT

We are grateful for the review comments of André Unger and Larry Myer (LBNL). This work was supported in part by the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems through the National Energy Technology Laboratory, and by Lawrence Berkeley National Laboratory under Department of Energy Contract No. DE-AC03-76SF00098.

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